ENCORE ACQUISITION CO
Form 10-K
March 10, 2005

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2004

Encore Acquisition Company
(Exact name of registrant as specified in its charter)

Delaware	**001-16295**	**75-2759650**
(State or other jurisdiction of incorporation)	*(Commission File Number)*	*(IRS Employer Identification No.)*

777 Main Street **Suite 1400** **Fort Worth, Texas**	**76102**
(Address of principal executive offices)	*(Zip Code)*

Registrant s telephone number, including area code:
(817) 877-9955
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**
Common Stock	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein and will not be contained, to the best of Registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2) Yes þ No o

Aggregate market value of the voting and non-voting common stock held by non-affiliates of the Registrant as of June 30, 2004 (the last business day of Registrant s most recently completed second fiscal quarter)	$	848,026,610
Number of shares of Common Stock, $0.01 par value, outstanding as of February 28, 2005		32,861,474

DOCUMENTS INCORPORATED BY REFERENCE

Parts of the definitive proxy statement for the Registrant s 2005 annual meeting of stockholders are incorporated by reference into Part III of this report on Form 10-K.

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This annual report on Form 10-K (the Report) contains forward-looking statements, which give our current expectations and forecasts of future events. The Private Securities Litigation Reform Act of 1995 provides a safe harbor for forward-looking statements made by or on behalf of Encore Acquisition Company or its subsidiaries. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation for a description of various factors that could materially affect the ability of Encore Acquisition Company to achieve the anticipated results described in the forward looking statements. Certain terms commonly used in the oil and natural gas industry and in this Report are defined at the end of Item 7A, beginning on page 50, under the caption Glossary of Oil and Natural Gas Terms. In addition, all production and reserve volumes disclosed in this Report represent amounts net to Encore Acquisition Company.

PART I

Items 1 and 2. *Business and Properties*

General

Our Business. We are a growing independent energy company engaged in the acquisition, development, exploitation, exploration, and production of onshore North American oil and natural gas reserves. Since our inception in 1998, we have sought to acquire high quality assets with potential for upside through low-risk development drilling projects. Our properties and our oil and natural gas reserves are located in four core areas: the Cedar Creek Anticline (CCA) in the Williston Basin of Montana and North Dakota; the Permian Basin of West Texas and Southeastern New Mexico; the Mid-Continent area, which includes the Arkoma and Anadarko Basins of Oklahoma, the ArkLaTx region of northern Louisiana and east Texas, and the Barnett Shale of north Texas; and the Rockies, which includes non-CCA assets in the Williston and Powder River Basins of Montana, and the Paradox Basin of southeastern Utah. For the three years ended December 31, 2004, we have invested $373.5 million in acquiring producing oil and natural gas properties, and we have invested an incremental $336.9 million on development and exploitation of our properties.

Most Valuable Asset. The CCA represented 66% of our total proved reserves as of December 31, 2004. The CCA is our most valuable asset today and in the foreseeable future. A large portion of our future success revolves around future exploitation of and production from this property through primary, secondary, and tertiary recovery techniques.

Recent Acquisitions.

<u>Cortez Oil & Gas, Inc.</u> On April 14, 2004, we purchased all of the outstanding capital stock of Cortez Oil & Gas, Inc. (Cortez), a privately held, independent oil and natural gas company, for a total purchase price of $127.0 million, which includes cash paid to Cortez former shareholders of $85.8 million, the repayment of $39.4 million of Cortez debt, and transaction costs incurred of $1.8 million.

The acquired oil and natural gas properties are located primarily in the CCA of Montana, the Permian Basin of West Texas and Southeastern New Mexico and in the Mid-Continent area, including the Anadarko and Arkoma Basins of Oklahoma and the Barnett Shale north of Fort Worth, Texas. Cortez operating results are included in our Consolidated Statement of Operations for the period from April through December 2004.

<u>Overton.</u> On June 17, 2004, we completed the acquisition of natural gas producing properties and undeveloped leases in the Overton Field located in Smith County, Texas for $83.1 million. The Overton Field assets are in the same core area as our interests in Elm Grove Field and have similar geology. Operating results for the Overton Field properties are included in our Consolidated Statement of Operations for the period from July through December 2004.

We identified over 100 drilling locations in the Travis Peak and Cotton Valley formations on the acreage in the Overton Field at the time of the acquisition. Subsequent to the close of the acquisition, we

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have implemented an active drilling program to develop the field. The properties produce primarily from multiple tight sandstone reservoirs in the Travis Peak and Cotton Valley formations at depths ranging between 8,000 and 11,500 feet. The production is 94% natural gas and the properties are 100% operated.

Drilling. In 2004, we drilled 168 gross operated productive wells and participated in drilling another 67 gross non-operated productive wells for a total of 235 gross productive wells for the year. On a net basis, we drilled 156.4 operated productive wells and participated in 8.8 non-operated productive wells in 2004. Out of the 168 (156.4 net) operated productive wells 12 (11.5 net) wells were service wells. We also drilled 5 (4.5 net) non-productive wells in 2004 of which 4 (3.9 net) were exploratory wells.

Oil and Natural Gas Production and Reserves. In 2004, our reserve growth was achieved through acquisitions, high-pressure air injection and drilling wells. We continue to pursue high-quality assets and to seek to replenish our drilling inventory through acquisitions, drilling extension wells and leasing acreage on which we can prospect.

The following table sets forth our total proved reserves, average daily production and reserve-to-production ratio, or R/P index, in our principal areas of operation as of December 31, 2004 and for the year then ended.

	Proved Reserves at December 31, 2004 (MBOE)	Percent of Total	Average Daily Production for 2004 (BOE/d)	Percent of Total	Average Daily Production Q4 2004(2) (BOE/d)	Percent of Total	Pro-Forma R/P Index(2)
Cedar Creek Anticline(1)	113,873	66%	13,660	55%	13,518	52%	23.0
Permian Basin	29,336	17%	5,368	22%	6,023	23%	13.3
Mid-Continent	22,835	13%	3,359	14%	4,441	17%	14.1
Rockies	7,009	4%	2,278	9%	2,114	8%	9.1
Total	173,053	100%	24,665	100%	26,096	100%	18.1

(1) Our CCA properties, which produce mainly from porous dolomites drilled on 40 to 80 acre spacing intervals, have longer reserve lives than our other properties because the low permeability level encountered within those producing intervals require a longer time to produce the reserves in place. This results in a lower production decline rate.

(2) R/ P index is a ratio used by management and the oil and natural gas industry to analyze the length of time the Company s reserves can generate cash flows at current production levels. This calculation is derived by dividing our total proved reserves into our production. In calculating the pro forma R/P index, we annualized our fourth quarter 2004 production because it includes production from both the Cortez and Overton acquisitions for the entire quarter. We believe this approach more accurately reflects our R/P index. Based on full year 2004 production, our R/P index was 22.8 for Cedar Creek Anticline, 14.9 for Permian Basin, 18.6 for Mid-Continent, 8.4 for Rockies, and 19.2 for all properties.

During 2004, we added 41.2 MMBOE of oil and natural gas reserves, which replaced 456% of the 9.0 MMBOE we produced in 2004. Our three year average reserve replacement ratio is 381%. The following table sets forth our calculation of our 2004, 2003, 2002, and three year average reserve replacement ratios (in thousands of BOE except percentages):

	Year Ended December 31,			
	2004	2003	2002	Three Year Average
Acquisition Reserve Replacement Ratio				
Changes in Proved Reserves:				
Acquisitions of minerals-in-place	22,239	6,257	15,461	43,957
Divided by:				
Production	9,027	8,110	7,399	24,536
Acquisition reserve replacement ratio	246%	77%	209%	179%
Development Reserve Replacement Ratio				
Changes in Proved Reserves:				
Extensions and discoveries	8,768	5,182	13,546	27,496
Improved recovery	11,812	12,744		24,556
Revisions of estimates	(1,629)	(3,493)	2,719	(2,403)
Total development program	18,951	14,433	16,265	49,649
Divided by:				
Production	9,027	8,110	7,399	24,536
Development reserve replacement ratio	210%	178%	220%	202%
Total Reserve Replacement Ratio				
Changes in Proved Reserves:				
Acquisitions of minerals-in-place	22,239	6,257	15,461	43,957
Extensions and discoveries	8,768	5,182	13,546	27,496
Improved recovery	11,812	12,744		24,556
Revisions of estimates	(1,629)	(3,493)	2,719	(2,403)
Total reserve additions	41,190	20,690	31,726	93,606
Divided by:				
Production	9,027	8,110	7,399	24,536
Total reserve replacement ratio	456%	255%	429%	381%

Business Strategies

Our primary business objective is to maximize internally generated cash flow and shareholder value by executing the following strategies:

Maintain an active development drilling program. Our technological expertise, combined with our proficient field operations and reservoir engineering, has allowed us to increase production and reserves on our properties through development drilling, workovers, waterflood enhancements, recompletions, and tertiary projects. Our plan is to maintain an inventory of exploitation and development projects that provide us ongoing drilling activity. Each year, we budget a portion of internally generated cash flow to secondary and tertiary recovery projects whose results will not be seen until future years.

Maximize existing reserves and production through high-pressure air injection. In addition to conventional development drilling, we utilize high-pressure air injection techniques on certain properties to enhance our growth. High-pressure air injection (HPAI) involves using compressors to inject air into producing oil and natural gas formations in order to displace remaining resident hydrocarbons and force them under pressure to a common lifting point for production. We believe that the HPAI programs on our CCA properties will generate a higher rate of return than other tertiary processes and can be applied throughout our CCA properties.

Expand our reserves, production, and drilling inventory through a disciplined acquisition program. We will continue to pursue acquisitions of properties with similar upside potential to our current portfolio of producing properties. Using the experience of our management team, we have developed and refined an acquisition program designed to increase our reserves and to complement our core properties, while providing upside potential. We have a staff of engineering and geoscience professionals who manage our core properties and use their experience and expertise to target and evaluate attractive acquisition opportunities. Following an acquisition, our technical professionals seek to enhance the value of the new assets through a proven development and exploitation program. We will continue to evaluate acquisition opportunities in 2005 with the same disciplined commitment to acquire assets that fit our portfolio and create value for our shareholders.

Explore for reserves. With the current high-priced commodity environment, we believe modest exploration programs can provide a rate of return comparable or superior to property acquisitions in certain areas. We seek to acquire undeveloped acreage and/or enter into drilling arrangements to explore in areas that complement our portfolio of properties. In keeping with our exploitation focus, the exploration projects are expected to set up multi-well exploitation projects if successful.

Operate in a cost effective, efficient, and safe manner. As of December 31, 2004, we operated properties representing approximately 85% of our proved reserves, which allows us to control capital allocation, operate in a safe manner, and control timing of investments.

Challenges to Implementing Our Strategy. We face a number of challenges to implementing our strategy and achieving our goals. Our primary challenge is to generate superior rates of return on our investments in a volatile commodity pricing environment, while replenishing our drilling inventory. Changing commodity prices affect the rate of return on a property acquisition, and the amount of our internally generated cash flow, and, in turn, can affect our capital budget. In addition to the changing commodity price risk, we face strong competition from independents and major oil companies. For more information on the challenges to implementing our strategy and achieving our goals, please read Factors That May Affect Future Results and Financial Condition beginning on page 42.

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Business Activities

The following table sets forth the net production, proved reserves quantities, and PV-10 values of our properties in our principal areas of operation:

Properties Principal Areas of Operations

	Net Production 2004				Proved Reserve Quantities at December 31, 2004			PV-10 at December 31, 2004	
	Oil (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent	Oil (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Amount(1)	Percent
								(In thousands)	
Cedar Creek Anticline	4,795	1,228	4,999	55%	110,802	18,426	113,873	$ 977,136	60%
Permian Basin	1,049	5,490	1,965	22%	15,693	81,858	29,336	340,659	21%
Mid-Continent	61	7,011	1,229	14%	1,283	129,310	22,835	226,472	14%
Rockies	774	360	834	9%	6,270	4,436	7,009	80,202	5%
Total	6,679	14,089	9,027	100%	134,048	234,030	173,053	$ 1,624,469	100%

(1) The pretax present value of estimated future revenues to be generated from the production of proved reserves, net of estimated production and future development costs; using prices and costs as of the date of estimation without future escalation; without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service, and depletion, depreciation, and amortization; and discounted using an annual discount rate of 10%. Giving effect to hedging transactions and using prices as of the date of estimation, our PV-10 value would have been decreased by $58.8 million at December 31, 2004. The Standardized Measure at December 31, 2004 is $1.2 billion. Standardized Measure differs from PV-10 by $458.9 million because Standardized Measure includes the effect of asset retirement obligations and future income taxes.

Operations

We act as operator of properties representing approximately 85% of our proved reserves at December 31, 2004. As operator, we are able to better control expenses, capital allocation, and the timing of exploitation and development activities of these properties. We also own properties that are operated by third parties, and, as working interest owners in those properties, we are required to pay our share of the costs of operating, exploiting, and developing them. See Properties Nature of Our Ownership Interests on page 13. During the years ended December 31, 2004, 2003, and 2002 our approximate costs for development activities on non-operated properties were $10.9 million, $5.4 million, and $3.4 million, respectively. We also own royalty interests in wells operated by third parties that are not burdened by lease operations expense or capital costs; however, we have little control over the implementation of projects on these properties.

Proved Reserves

Proved developed reserves are proved reserves that are expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells drilled to known reservoirs on acreage yet to be drilled for which the existence and recoverability of such reserves can be estimated with reasonable certainty, or from existing wells where a relatively major expenditure is required to establish production. Proved undeveloped reserves also include unrealized production response from fluid injection and other improved recovery techniques, such as high-pressure air injection, where such techniques have been proven effective by actual tests in the area and in the same reservoir.

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The following table sets forth estimated period end proved reserves for the periods indicated as estimated by Miller and Lents, Ltd., independent petroleum engineers (in thousands except per Bbl and per Mcf amounts):

	As of December 31,		
	2004	**2003**	**2002**
Oil (Bbls)			
Developed	97,114	92,377	93,945
Undeveloped	36,934	25,355	17,729
Total	134,048	117,732	111,674
Natural Gas (Mcf)			
Developed	156,919	104,767	82,217
Undeveloped	77,111	34,183	17,601
Total	234,030	138,950	99,818
Combined (BOE)			
Developed	123,267	109,838	107,648
Undeveloped	49,786	31,052	20,662
Total(1)	173,053	140,890	128,310
PV-10(2)			
Developed	$ 1,296,201	$ 844,873	$ 732,823
Undeveloped	328,268	176,201	132,281
Total	$ 1,624,469	$ 1,021,074	$ 865,104
Standardized Measure(3)	$ 1,165,619	$ 736,939	$ 624,718
Reserve price assumptions			
Oil ($/Bbl)	$ 43.46	$ 32.55	$ 31.20
Natural gas ($/Mcf)	6.19	5.83	4.79

(1) Volumetric reserves attributed to the net profits interests in our CCA properties were 24,774 MBOE, 20,623 MBOE, and 16,262 MBOE, respectively, at December 31, 2004, 2003, and 2002. See Net Profits Interests on page 14. The volumes attributed to the net profits interests, which reduce our reserves on a BOE-for-BOE basis, will fluctuate from period to period primarily based on commodity prices and the level of planned development expenditures.

(2) The pretax present value of estimated future revenues to be generated from the production of proved reserves; net of estimated future production and future development costs; using prices and costs as of the date of estimation without future escalation; without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service, and depletion, depreciation, and amortization; and discounted

using an annual discount rate of 10%. Giving effect to hedging transactions and using prices as of the date of estimation, our PV-10 value would have been $1.6 billion at December 31, 2004, $997.2 million at December 31, 2003, and $860.6 million at December 31, 2002.

(3) Estimated future cash inflows to be generated from the production and sale of proved oil and natural gas reserves, net of estimated future production and development costs, asset retirement obligations and future income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure differs from PV-10 by $458.9 million because Standardized Measure includes the effect of asset retirement obligations and future income taxes.

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There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of exploitation expenditures. The data in the above table represents estimates only. Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly, and estimates of other engineers might differ materially from those shown above. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Results of drilling, testing, and production, after the date of the estimate, may justify revisions. Accordingly, reserve estimates may vary significantly from the quantities of oil and natural gas that are ultimately recovered.

Future prices received for production and future costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The PV-10 reserve value shown should not be construed as the current market value of the reserves. The 10% discount factor used to calculate present value, which is mandated by Statement of Financial Accounting Standard No. 69, Disclosures about Oil and Gas Producing Activities, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate. For properties that we operate, future production expenses exclude our share of contractual overhead charges. In addition, the calculation of estimated future costs does not take into account the effect of various cash outlays.

During the calendar year 2004, we filed estimates of oil and natural gas reserves at December 31, 2003 with the U.S. Department of Energy on Form EIA-23. As required for the EIA-23, the filing reflected only production that comes from our operated wells at year end, and is reported on a gross basis. Those estimates came directly from our reserve report prepared by Miller and Lents, Ltd., who are independent petroleum engineers.

Production and Price History

The following table sets forth information regarding net production of oil and natural gas, certain price information, including the effects of hedging, and average costs per BOE for each of the periods indicated:

	Year Ended December 31,		
	2004	**2003**	**2002**
Production:			
Oil (MBbls)	6,679	6,601	6,037
Natural gas (MMcf)	14,089	9,051	8,175
Combined (MBOE)	9,027	8,110	7,399
Average Daily Production:			
Oil (Bbls/d)	18,249	18,085	16,540
Natural gas (Mcf/d)	38,493	24,798	22,397
Combined (BOE/d)	24,665	22,218	20,273
Average Prices:			
Oil (per Bbl)	$ 33.04	$ 26.72	$ 22.34
Natural gas (per Mcf)	5.53	4.83	3.16
Combined (per BOE)	33.07	27.14	21.72
Average Costs per BOE:			
Lease operations expense	$ 5.22	$ 4.67	$ 4.15
Production, ad valorem, and severance taxes	3.36	2.71	2.12
Depletion, depreciation, and amortization	5.38	4.13	4.67
General and administrative (excluding non-cash stock based compensation)	1.22	1.07	0.83

Producing Wells

The following table sets forth information at December 31, 2004 relating to the producing wells in which we owned a working interest as of that date. We also held royalty interests in units and acreage beyond the wells in which we have a working interest. Wells are classified as oil or natural gas wells according to their predominant production stream. Gross wells are the total number of producing wells in which we have an interest, and net wells are determined by multiplying gross wells by our average working interest.

	Oil Wells			Natural Gas Wells		
	Gross Wells	Net Wells	Average Working Interest	Gross Wells	Net Wells	Average Working Interest
Cedar Creek Anticline	700	614.5	88%	13	4.6	35%
Permian Basin	1,416	364.8	26%	444	177.1	40%
Rockies	546	299.3	55%			0%
Mid-Continent	112	14.4	13%	524	103.3	20%
Total	2,774(1)	1,293.0	47%	981(1)	285.0	29%

(1) Our total wells include 1,595 operated wells and 2,160 non-operated wells. At December 31, 2004, 13 of our wells have multiple completions.

Acreage

The following table sets forth information at December 31, 2004 relating to acreage held by us. Developed acreage is assigned to producing wells. Undeveloped acreage is acreage held under lease, permit, contract, or option that is not in a spacing unit for a producing well, including leasehold interests identified for exploitation or exploratory drilling. Our undeveloped acreage is concentrated in our Montana properties, which represents 87% of our total undeveloped acreage. These leases expire at various dates ranging from 2005 to 2017, with leases representing $0.3 million of cost set to expire in 2005 if not developed.

	Gross Acreage	Net Acreage
Developed acreage	350,489	179,387
Undeveloped acreage	562,241	398,042
Total	912,730	577,429

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Drilling Results

The following table sets forth information with respect to wells drilled during the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found, or economic value. Development wells are wells drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive. Exploratory wells are wells drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir. Productive wells are those that produce commercial quantities of hydrocarbons, exclusive of their capacity to produce at a reasonable rate of return.

	Year Ended December 31,					
	2004		2003		2002	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	203	135.5	137	103.0	109	95.3
Non-productive	1	0.6	1	0.7		
Total development	204	136.1	138	103.7	109	95.3
Exploratory Wells						
Productive	32	29.7				
Non-productive	4	3.9				
Total development	36	33.6				
All Wells Drilled						
Total productive wells drilled	235	165.2	137	103.0	109	95.3
Total dry holes drilled	5	4.5	1	0.7		
Grand total	240	169.7	138	103.7	109	95.3

Present Activities

As of December 31, 2004, we had a total of 14 gross (7.9 net) wells that had been spud and were in varying stages of drilling operations, of which 3 gross (2.2 net) wells were exploratory wells. Also, there were 34 gross (27.0 net) wells that had reached total depth and were in varying stages of completion pending first production, of which 12 gross (11.6 net) wells were exploratory wells.

We are implementing the expansion of the HPAI program to the entire north end of the Pennel unit of the Cedar Creek Anticline, which we expect to complete by the end of 2005. We plan to begin high-pressure air injection in the second quarter of 2005.

We have implemented the first two phases of the HPAI program for the Little Beaver unit in the Cedar Creek Anticline. Air injection has been ongoing since December 2003, and the reservoir is pressuring up as expected.

Delivery Commitments and Marketing

Consistent with industry practices, our oil and natural gas production is principally sold to end users, marketers, refiners, and other purchasers having access to nearby pipeline facilities. In areas where there is no practical access to pipelines, oil is trucked to storage facilities. While we typically market our oil and gas production for a term of a year or less, we entered into an agreement in 2004 to sell at least 2,500 barrels of oil per day at a floating market price through 2009.

For the fiscal year 2004, our largest purchasers included Shell and ConocoPhillips, which respectively accounted for 29% and 27% of total oil and natural gas sales. Our marketing of oil and natural gas can be affected by factors beyond our control, the potential effects of which cannot be accurately predicted.

Management is of the opinion that the loss of any one purchaser would not have a material adverse effect on our ability to market our oil and natural gas production.

The sale of our CCA oil production is dependent on transportation to markets through Butte Pipeline to Guernsey, Wyoming. Any restrictions on the available capacity for us to transport oil in this pipeline could have a material adverse effect on our price we receive and our oil revenues.

Competition

We compete with major and independent oil and natural gas companies. Some of our competitors have substantially greater financial and other resources than we do. In addition, larger competitors may be able to absorb the burden of any changes in federal, state, provincial, and local laws and regulations more easily than we can, adversely affecting our competitive position. Our competitors may be able to pay more for productive oil and natural gas properties and may be able to define, evaluate, bid for, and purchase a greater number of properties and prospects than we can. Further, these companies may enjoy technological advantages and may be able to implement new technologies more rapidly than we can. Our ability to acquire additional properties in the future will depend upon our ability to conduct efficient operations, evaluate and select suitable properties, implement advanced technologies, and consummate transactions in this highly competitive environment.

Federal and State Regulations

Compliance with applicable federal and state regulations is often difficult and costly, and non-compliance may result in substantial penalties. The following are some specific regulations that may affect us. We cannot predict the impact of these or future legislative or regulatory initiatives.

Federal Regulation of Natural Gas. The interstate transportation and sale for resale of natural gas is subject to federal regulation, including transportation rates and various other matters, by the Federal Energy Regulatory Commission (FERC). Federal wellhead price controls on all domestic natural gas were terminated on January 1, 1992 and none of our natural gas sales are currently subject to FERC regulation. We cannot predict the impact of future government regulation on any natural gas operations.

Although FERC s regulations should generally facilitate the transportation of natural gas produced from our properties and the direct access to end-user markets, the future impact of these regulations on marketing our production or on our natural gas transportation business cannot be predicted. We do not believe, however, that we will be affected differently than competing producers and marketers.

Federal Regulation of Oil. Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at market prices. The net price received from the sale of these products is affected by market transportation costs. A significant part of our oil production is transported by pipeline. Under rules adopted by FERC effective January 1995, interstate oil pipelines can change rates based on an inflation index, though other rate mechanisms may be used in specific circumstances. The United States Court of Appeals upheld FERC s orders in 1996. These rules have had little effect on our oil transportation cost.

State Regulation. Oil and natural gas operations are subject to various types of regulation at the state and local levels. Such regulation includes requirements for drilling permits, the method of developing new fields, the spacing and operations of wells, and waste prevention. The production rate may be regulated and the maximum daily production allowable from oil and natural gas wells may be established on a market demand or conservation basis. These regulations may limit production by well and the number of wells that can be drilled.

Federal, State or Native American Leases. Our operations on federal, state or Native American oil and natural gas leases are subject to numerous restrictions, including nondiscrimination statutes. Such operations must be conducted pursuant to certain on-site security regulations and other permits and authorizations issued by the Bureau of Land Management, Minerals Management Service and other agencies.

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Environmental Regulations. Various federal, state and local laws regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment, directly impact oil and natural gas exploration, development and production operations, and consequently may impact our operations and costs. Management believes that we are in substantial compliance with applicable environmental laws and regulations. To date, we have not expended any material amounts to comply with such regulations, and we do not currently anticipate that future compliance will have a materially adverse effect on our consolidated financial position, cash flows, or results of operations.

Operating Hazards and Insurance

The oil and natural gas business involves a variety of operating risks, including fires, explosions, blowouts, environmental hazards, and other potential events that can adversely affect our operations. Any of these problems could adversely affect our ability to conduct operations and cause us to incur substantial losses. Such losses could reduce or eliminate the funds available for exploration, exploitation, or leasehold acquisitions or result in loss of properties.

In accordance with industry practice, we maintain insurance against some, but not all, potential risks and losses. We do not carry business interruption insurance. We may not obtain insurance for certain risks if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable at a reasonable cost. If a significant accident or other event occurs that is not fully covered by insurance, it could adversely affect us.

Employees

We had 164 employees as of December 31, 2004, 62 of which were field personnel. None of the employees are represented by any union. We consider our relations with our employees to be good.

Principal Executive Office

Our principal executive offices are located at 777 Main Street, Suite 1400, Fort Worth, Texas 76102. Our main telephone number is (817) 877-9955.

Available Information

We make available electronically, free of charge through our website (www.encoreacq.com), our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and other items filed with the SEC pursuant to Section 13(a) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with or furnish such material to the SEC. In addition, the public may read and copy any materials that we file with the SEC at the SEC s Public Reference Room at 450 Fifth Street, NW, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains a website (www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers, like us, that file electronically with the SEC.

We have adopted a code of business conduct and ethics that applies to all directors, officers, and employees, including our principal executive officer and senior financial officers. The code of business conduct and ethics is available on our Internet website (www.encoreacq.com). In the event that we make changes in, or provide waivers from, the provisions of this code of business conduct and ethics that the SEC or the New York Stock Exchange (NYSE) require us to disclose, we intend to disclose these events on our website.

We have filed the required certifications under Section 302 of the Sarbanes-Oxley Act of 2002 as Exhibits 31.1 and 31.2 to this Report. In 2004, we submitted to the NYSE the CEO certification required by Section 303A.12(a) of the NYSE s Listed Company Manual. In 2005, we expect to submit this certification to the NYSE after the annual meeting of stockholders.

Our board of directors currently has three standing committees: (1) audit, (2) compensation, and (3) nominating and corporate governance. The charters of our board of director committees are available on our website. Copies of the code of business conduct and ethics and board committee charters are also available in print upon written request to the Corporate Secretary, Encore Acquisition Company, 777 Main Street, Suite 1400, Fort Worth, Texas 76102.

The information on our website or any other website is not incorporated by reference into this Report.

Properties

Nature of Our Ownership Interests

We own interests in oil and natural gas properties located in four core areas: the CCA in the Williston Basin of Montana and North Dakota; the Permian Basin of West Texas and Southeastern New Mexico; the Mid-Continent area, which includes the Arkoma and Anadarko Basins of Oklahoma, the ArkLaTx region of northern Louisiana and east Texas, and the Barnett Shale of north Texas; and the Rockies, which includes non-CCA assets in the Williston and Powder River Basins of Montana, and the Paradox Basin of southeastern Utah. Substantially all of our PV-10 reserve value at December 31, 2004 was attributable to working interests in oil and natural gas properties. A working interest in an oil and natural gas lease requires us to pay our proportionate share of the costs of drilling and production.

Cedar Creek Anticline Properties Montana and North Dakota

Our initial purchase of interests in the CCA was on June 1, 1999, and we have subsequently acquired additional working interests from various owners. The most recent addition to our CCA holdings was 37 wells acquired in the Cortez acquisition in April 2004. Presently, we operate approximately 99.4% of our CCA properties with an average working interest of approximately 87.4%. The average daily production from our CCA properties during 2004 was 13,660 BOE per day.

The CCA is a major structural feature of the Williston Basin in southeastern Montana and northwestern North Dakota. Our acreage is concentrated on the two to six mile wide crest of the CCA, giving us access to the greatest accumulation of oil in the structure. Our holdings extend for approximately 120 continuous miles along the crest of the CCA across five counties in two states. Primary producing reservoirs are the Red River, Stony Mountain, Interlake, and Lodgepole formations at depths of between 7,000 feet and 9,000 feet.

Since taking over operations, along with subsequent additional acquired interests, we have increased production by 73.2% on the CCA from 7,807 BOE per day (average for June 1999) to 13,518 BOE per day (average for the fourth quarter 2004). We have accomplished ongoing production growth through a combination of:

- additional acquisition of interests;
- detailed attention to the existing wellbores;
- the addition of strategically positioned new horizontal and vertical wellbores;
- the application of horizontal re-entry drilling in existing wellbores;
- waterflood enhancements; and
- implementation of our high-pressure air injection program.

In 2004, we drilled 82 gross wells on the CCA, of which 46 were horizontal re-entry wells that reestablished production from non-producing wells, added additional barrels from existing producing wells and serve as injection wells for secondary and tertiary recovery projects. Including our HPAI project, we incurred $116.5 million and $77.6 million of capital projects on the CCA during 2004 and 2003, respectively.

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Our outlook for sustained production growth on the CCA remains strong. We plan to continue the development of the reserve base through currently identified opportunities and future opportunities resulting from knowledge gained through continued study and ongoing drilling and exploitation efforts on these properties. We believe that HPAI continues to be our most significant source of sustained production growth on the CCA.

The CCA represents 66% of our total proved reserves as of December 31, 2004. The CCA represents our most valuable asset today and in the foreseeable future. A large portion of our future success revolves around future conventional exploitation, production, and success of HPAI projects on these properties.

High-pressure air injection. In 2004 we continued our high-pressure air injection program at the CCA. High-pressure air injection is a tertiary recovery technique that involves using compressors to inject air into oil and natural gas formations in order to displace remaining resident hydrocarbons and force them under pressure to a common lifting point for production.

In 2002 we initiated a HPAI project that injects air into the Red River U4 zone in the Pennel unit of the CCA. The Red River U4 zone is the same zone where high-pressure air injection has been successfully implemented by other operators in adjacent areas on the CCA. We have seen positive results from this high-pressure air injection project at Pennel. Based on these results, we are in the process of expanding high pressure air injection to other areas in the CCA. We believe that high-pressure air injection technology can be applied throughout the CCA and that it may yield significant new reserves. We believe that the high-pressure air injection will generate a higher rate of return than other tertiary processes on the CCA.

The Phase I project at Pennel continues to perform well with production uplift on target with our original projection. In addition to the 0.7 million BOE of reserves booked in Pennel by December 31 2003, we added 6.1 million BOE of reserves in the Phase II HPAI area at Pennel in 2004. We expect to begin injecting air in the Phase II area during the first half of 2005. Phase II implementation is anticipated to be complete by the end of 2005. The Pennel project will receive the majority of the total $26.0 million budgeted for high-pressure air injection capital in 2005.

In 2003, we established a HPAI project in the Little Beaver unit of the CCA. We negotiated a compression services agreement from an offset operator to provide high-pressure air for the project. This agreement allowed us to install a high-pressure air injection project in less than one year. In 2003, we added 12.2 million BOE of reserves for the project. In 2004, we added an additional 3.0 million BOE of HPAI reserves for the Little Beaver unit because we expanded the scope of the project. Air injection has been ongoing since December 2003, and the reservoir is pressuring up as expected. The project is on schedule, and initial production uplift is expected by mid-2005.

We believe that much of our acreage in the CCA has potential opportunities for utilizing HPAI recovery techniques at economic rates of return. We continue to evaluate and perform engineering studies on these projects. Over the next several years, we plan to implement these development projects initially in the Red River U4 zone of the CCA. Additionally, we have other zones in the CCA that currently produce oil and may provide additional HPAI opportunities. We believe these zones can be most economically evaluated for HPAI opportunities after assessing HPAI in the Red River U4 zone.

Net Profits Interests. A major portion of our acreage position in the CCA is subject to net profits interests (NPI) ranging from 1% to 50%. The holders of these net profits interests are entitled to receive a fixed percentage of the cash flow remaining after specified costs have been subtracted from net revenue. The net profits calculations are contractually defined, but in general, net profits are determined after considering operating expense, overhead expense, interest expense, and drilling costs. The amounts of reserves and production calculated to be attributable to these net profits interests are deducted from our reserves and production data, and our revenues are reported net of NPI payments. The reserves and production that are attributed to the NPIs are calculated by dividing estimated future NPI payments (in the case of reserves) or prior period actual NPI payments (in the case of production) by the commodity prices current at the determination date. Fluctuations in commodity prices and the levels of development activities in the CCA from period to period will impact the reserves and production attributed to the NPIs and will have an inverse effect on our reported reserves and production. For the years ended December 31, 2004, 2003, and 2002, we reduced revenue for the payments of the net profits interests by $12.6 million, $5.8 million, and $2.0 million, respectively.

Permian Basin Properties West Texas and New Mexico

Our Permian Basin properties include sixteen operated fields including East Cowden Grayburg Unit, Fuhrman-Nix, Henderson, Sand Hills and others; and sixteen non-operated fields including Indian Basin, North Cowden, Ozona, Yates, and others. Production from the Central Permian comes from multiple reservoirs including the Grayburg, San Andres, Glorieta, Tubb, and Pennsylvanian zones. Production from the southern portion of the Permian Basin comes mainly from the Canyon and Strawn Formations with multiple pay intervals.

Continued development opportunities remain on these properties. During 2004, we drilled 76 wells on the Permian properties primarily in the Sand Hills, Furhman-Nix, and Ozona fields. We invested approximately $32.4 million of development capital on our Permian properties. Average daily production in 2004 was 5,368 BOE per day. We believe these properties will be an area of growth over the next several years.

Mid-Continent Properties Oklahoma, Arkansas, East Texas, North Texas, Kansas, and North Louisiana

Oklahoma, Arkansas, North Texas, and Kansas

We own various interests, including operated, non-operated, royalty and mineral interests, on properties located in the Anadarko Basin of western Oklahoma and the Arkoma Basin of eastern Oklahoma, and eastern Arkansas. These properties produce primarily gas, and to a lesser extent oil, from various horizons. We also have operated interests in properties producing from the Barnett Shale in north Texas, and interests in properties in the Hugoton Basin in Kansas. During 2004, we invested $11.9 million of development capital in these properties. Average production in the fourth quarter of 2004 was 11,284 Mcfe per day.

ArkLaTx North Louisiana and East Texas

The ArkLaTx properties consist of operated working interests, non-operated working interests, and undeveloped leases acquired in the Elm Grove and Overton acquisitions. For the fourth quarter of 2004, the average daily production for the properties was 15,366 Mcfe per day. We invested approximately $20.9 million of capital to develop these properties during 2004. We believe these properties are an area of growth for us.

The Elm Grove properties were purchased on July 31, 2003 at a cost of $54.6 million. Subsequent to the initial acquisition, we purchased additional interests in the properties. Our interests are located in the Elm Grove Field in Bossier Parish, Louisiana. The acquired properties include non-operated working interests ranging from 1% to 47% across 1,800 net acres in 15 sections.

On June 17, 2004, we completed the acquisition of natural gas producing properties and undeveloped leases in the Overton Field located in Smith County, Texas for $83.1 million. The Overton properties have a larger proportion of proved undeveloped reserves than most of our historical acquisitions. The Overton Field assets are in the same core area as our interests in Elm Grove Field and have similar geology. The properties are producing primarily from multiple tight sandstone reservoirs in the Travis Peak and Lower Cotton Valley formations at depths ranging between 8,000 and 11,500 feet. The production is 94% natural gas and the properties are 100% operated by us. We identified over 100 drilling locations in the Travis Peak and Lower Cotton Valley formations on the acreage in Overton Field at the time of the acquisition. Subsequent to the close of the acquisition, we have implemented an active drilling program to develop the field.

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Rocky Mountain Properties North Dakota, Montana, and Utah

Lodgepole North Dakota

The Lodgepole properties consist of working and overriding royalty interests in several geographically concentrated fields. The Lodgepole properties are located in the Williston Basin in western North Dakota near the town of Dickinson, approximately 120 miles from our CCA properties. The Lodgepole properties produce exclusively from the Mississippian-aged Lodgepole Formation, and the Eland Unit is the largest accumulation in the trend. The average production from the Lodgepole properties was 1,224 BOE per day for 2004. In 2004, we invested an insignificant amount of capital in the Lodgepole properties.

The Lodgepole properties produce from reefs with high permeability and thick oil columns. The prolific nature of these reservoirs makes future engineering estimates related to ultimate recovery of reserves inherently difficult to determine. If the properties performance varies significantly from the Miller and Lents, Ltd. estimates of reserves, then our future cash flows could be affected in 2005 and a few years beyond.

Bell Creek Montana

The Bell Creek properties are located in the Powder River Basin of southeastern Montana. We operate the seven production units that comprise the Bell Creek properties, each with a 100% working interest. The shallow (less than 5,000 feet) Cretaceous-aged Muddy Sandstone reservoir produces 100% oil. We invested $0.7 million of capital in these properties in 2004. The average daily production from the Bell Creek properties was 355 BOE per day during 2004. In the fall of 2005, we intend to initiate a small field test of new technology called Microbial Enhanced Oil Recovery (MEOR) in conjunction with the State of Montana, MSE Technology Applications Center for Innovations and Montana Tech. This process may enhance oil production by creating a natural Bio-film which diverts injected water towards un-swept oil.

Paradox Basin Utah

The Paradox Basin properties, located in southeast Utah s Paradox Basin, are divided between two prolific oil producing units: the Ratherford Unit operated by ExxonMobil and the Aneth Unit operated by Resolute Natural Resources Company. Our average net production from the properties for 2004 was approximately 699 BOE per day. We believe these properties have potential horizontal redevelopment, secondary development, and tertiary recovery potential. Our development capital for these properties was $0.1 million during 2004.

Shallow Gas Montana

We have begun a project to explore for natural gas in the shallow zones of our acreage in north central Montana. The primary producing horizon in this area is the Eagle Sandstone, which produces from reservoir depths between 800 feet and 1,200 feet. This Eagle Sandstone has produced large quantities of gas to date from numerous fields across northern Montana. We invested $4.3 million in capital during 2004 to drill a total of 11 wells. Three of the wells were completed as productive and began producing natural gas in early 2005 for a capital investment of $0.8 million, five wells are being evaluated for completion, and three wells were expensed as dry holes in 2004 for a total cost of $0.8 million.

All wells that we drilled in this area in 2004, and any that we may drill in the future, will likely be classified as exploratory in nature. As such, the success rate of these wells will be lower than our historical average. Additionally, there can be no guarantee that reserves will be found in a sufficient quantity as to make them economically producible. If reserves are not found in a quantity that would make them economically producible, all costs to drill the well, as well as any related undeveloped leasehold costs associated with the lease on which the well was drilled, would be expensed in the period in which the determination was made.

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Title to Properties

We believe that our title to our oil and natural gas properties is good and defensible in accordance with standards generally accepted in the oil and natural gas industry.

Our properties are subject, in one degree or another, to one or more of the following:

- royalties, overriding royalties, net profit interests, and other burdens under oil and natural gas leases;
- contractual obligations, including, in some cases, development obligations arising under operating agreements, farmout agreements, production sales contracts, and other agreements that may affect the properties or their titles;
- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing unpaid suppliers and contractors, and contractual liens under operating agreements;
- pooling, unitization and communitization agreements, declarations, and orders; and
- easements, restrictions, rights-of-way, and other matters that commonly affect property.

We believe that the burdens and obligations affecting our properties do not in the aggregate materially interfere with the use of the properties. As indicated under Net Profits Interests above, a major portion of our acreage position in the CCA, our primary asset, is subject to net profits interests.

ITEM 3. *Legal Proceedings*

We are not currently a party to any material legal proceeding of which we are aware.

ITEM 4. *Submission of Matters to a Vote of Security Holders*

There were no matters submitted to stockholders during the quarter ended December 31, 2004.

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PART II

Item 5. ***Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Our common stock, $0.01 par value, is listed on the NYSE under the symbol EAC. The following table sets forth quarterly high and low sales prices of our common stock for each quarterly period of 2004 and 2003:

	High	Low
2004		
Quarter ended December 31	$ 36.88	$ 30.56
Quarter ended September 30	34.75	25.49
Quarter ended June 30	31.50	24.81
Quarter ended March 31	28.85	23.65
2003		
Quarter ended December 31	$ 25.28	$ 19.60
Quarter ended September 30	22.15	17.80
Quarter ended June 30	20.01	17.00
Quarter ended March 31	19.35	16.63

On February 28, 2005, we had approximately 220 shareholders of record.

Dividends

No dividends have been declared or paid on our common stock. We anticipate that we will retain all future earnings and other cash resources for the future operation and development of our business. Accordingly, we do not intend to declare or pay any cash dividends in the foreseeable future. Payment of any future dividends will be at the discretion of our board of directors after taking into account many factors, including our operating results, financial condition, current and anticipated cash needs, and plans for expansion. The declaration and payment of dividends is restricted by our existing credit agreement and the indentures governing our $8^3/8$% and $6^1/4$% notes. Future debt agreements may also restrict our ability to pay dividends.

Item 6. ***Selected Financial Data***

The following selected consolidated financial data should be read in conjunction with Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data (in thousands except per share and per unit data):

	Year Ended December 31,				
	2004	**2003**	**2002**	**2001**	**2000**
Consolidated Statement of Operations Data:					
Revenues(1):					
Oil	$ 220,649	$ 176,351	$ 134,854	$ 105,768	$ 92,441
Natural gas	77,884	43,745	25,838	30,149	16,509
Total revenues	$ 298,533	$ 220,096	$ 160,692	$ 135,917	$ 108,950
Net income (loss)	$ 82,147	$ 63,641(2)	$ 37,685	$ 16,179(3)	$ (2,135)(4)
Net income (loss) per common share:					
Basic	$ 2.62	$ 2.11	$ 1.25	$ 0.56	$ (0.09)
Diluted	2.58	2.10	1.25	0.56	(0.09)
Weighted average number of common shares outstanding:					
Basic	31,393	30,102	30,031	28,718	22,806
Diluted	31,825	30,333	30,161	28,723	22,806
Consolidated Statement of Cash Flows Data:					
Cash provided by (used by):					
Operating activities	$ 171,821	$ 123,818	$ 91,509	$ 80,212	$ 44,508
Investing activities	(433,470)	(153,747)	(159,316)	(89,583)	(99,236)
Financing activities	262,321	17,303	80,749	8,610	49,107
Production:					
Oil (Bbls)	6,679	6,601	6,037	4,935	3,961
Natural gas (Mcf)	14,089	9,051	8,175	8,078	4,303
Combined (BOE)	9,027	8,110	7,399	6,281	4,678
Average Sales Price:					
Oil ($/Bbl)	$ 33.04	$ 26.72	$ 22.34	$ 21.43	$ 23.34
Natural gas ($/Mcf)	5.53	4.83	3.16	3.73	3.84
Combined ($/BOE)	33.07	27.14	21.72	21.64	23.29
Costs per BOE:					
Lease operations	$ 5.22	$ 4.67	$ 4.15	$ 4.00	$ 3.99
Production, ad valorem, and severance taxes	3.36	2.71	2.12	2.20	3.24
Depletion, depreciation, and amortization	5.38	4.13	4.67	5.05	4.72

General and administrative (excluding non-cash stock based compensation)	1.22	1.07	0.83	0.80	0.93

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	Year Ended December 31,				
	2004	2003	2002	2001	2000
Proved Reserves:					
Oil (Bbls)	134,048	117,732	111,674	91,369	78,910
Natural gas (Mcf)	234,030	138,950	99,818	75,687	72,970
Combined (BOE)	173,053	140,890	128,310	103,983	91,072

	As of December 31,				
	2004	2003	2002	2001	2000
Consolidated Balance Sheet Data:					
Working capital	$ (15,566)	$ (52)	$ 12,489	$ 1,107	$ (15,275)
Total assets	1,123,400	672,138	549,896	402,000	343,756
Total debt	379,000	179,000	166,000	79,107	162,045
Stockholders equity	473,575	358,975	296,266	269,302	147,811

(1) For the years ended December 31, 2004, 2003, 2002, 2001, and 2000 we reduced revenue for the payments of the net profits interests by $12.6 million, $5.8 million, $2.0 million, $2.8 million, and $11.5 million, respectively.

(2) Net income for the year ended December 31, 2003 includes a $0.9 million cumulative effect of accounting change, which affects its comparability with other periods presented. See Pro Forma amounts presented in Note 5. Asset Retirement Obligations to the accompanying consolidated financial statements.

(3) Net income for the year ended December 31, 2001 includes $9.6 million of non-cash compensation expense, $4.3 million of bad debt expense, $1.6 million of impairment of oil and natural gas properties, and a $(0.9) million cumulative effect of accounting change, which affects its comparability with other periods presented.

(4) Net income for the year ended December 31, 2000 includes $26.0 million of non-cash compensation expense, which affects its comparability with other periods presented.

Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

The following discussion and analysis of our consolidated financial position and results of operations should be read in conjunction with our financial statements and notes and the supplemental oil and natural gas disclosures included elsewhere in this Report. The following discussion and analysis contains forward-looking statements, including, without limitation, statements relating to our plans, strategies, objectives, expectations, intentions, and resources. The words anticipate, estimate, expect, project, intend, plan, believe, should and similar exp identify forward-looking statements. Actual results could differ materially from those stated in the forward-looking statements. We do not undertake to update, revise or correct any of the forward-looking information unless required to do so under the federal securities laws. Readers are cautioned that such forward-looking statements should be read in conjunction with our disclosures under the headings: Special Note Regarding Forward-Looking Statements beginning on page 41 and Factors That May Affect Future Results and Financial Condition beginning on page 42.

Overview

We engage in the acquisition, development, exploitation, exploration, and production of onshore North American oil and natural gas reserves. Our business strategies include maintaining an active low-risk development drilling program, maximizing existing reserves and production through high-pressure air injection projects, expanding our reserves, production and drilling inventory through a disciplined acquisition program, exploring for reserves and operating in a cost effective, efficient, and safe manner.

Our financial results and ability to generate cash depend upon many factors, particularly the price of oil and natural gas. Commodity prices strengthened considerably in 2004. The average oil price for the NYMEX futures market was $41.26 per barrel for 2004 as compared to $31.04 per barrel for 2003. The average natural gas price for the NYMEX futures market was $6.11 per MMBTU for 2004 as compared to $5.50 per MMBTU for 2003. Commodity prices are influenced by many factors that are outside of our control. We cannot predict future commodity prices. For this reason, we attempt to mitigate the effect of commodity price risk by hedging a portion of our future production.

In 2004, we saw the industry and commodity markets begin to reflect a higher long-term outlook for commodity prices. As a result during the year, the industry continued to bid up the price of reserves to historically high levels. However, we were fortunate to be able to expand our core areas with the purchase of Cortez Oil & Gas, Inc. and natural gas properties in the Overton Field. As the year progressed and the cost of acquisitions continued to rise, we began to identify exploration projects within our core areas that complemented our current asset portfolio. We believe the rate of return on our exploration projects will meet or exceed the rate of return available in the current acquisition market. We will, however, continue to evaluate acquisition opportunities as they arise and to the extent we believe we can expect to realize a good rate of return to our shareholders.

We continue to believe that a portfolio of long-lived quality assets will position the Company for future success, and that reserve replacement is a key statistical measure of our success in growing our asset base. During 2004, we replaced 456% of our 2004 production. Our development program replaced 210% of production and acquisitions replaced 246% of production. See Business and Properties General Oil and Natural Gas Production and Reserves on page 3 for the calculation of our reserve replacement ratios.

Also in 2004, we continued to see positive results from our Phase I high-pressure air injection project at the Pennel unit. Pennel is the largest unit of the CCA units. The Phase II implementation is anticipated to be complete by the end of 2005 and initial air injection is scheduled to begin in the second quarter of 2005. In the Little Beaver unit at the southern end of the CCA, we have completed the implementation of Phase I and II HPAI projects. Our independent reserve engineers, Miller and Lents, Ltd. estimated that we added 9.1 million and 12.5 million barrels, respectively, of proved undeveloped oil reserves associated with our high pressure air injection program at the end of 2004 and 2003. For the long term, we believe that high-pressure air injection technology can be applied throughout the Cedar Creek Anticline.

2004 Highlights

Our financial and operating results for the year ended December 31, 2004 include the following:

Oil and natural gas reserves increased 23% to 173 MMBOE. During 2004, we added 41.2 MMBOE, replacing 456% of the 9.0 MMBOE produced in 2004. See Business and Properties General Oil and Natural Gas Production and Reserves on page 3 for the calculation of our reserve replacement ratio. Oil reserves accounted for 77% of total proved reserves, and 71% of proved reserves are developed. The estimated pretax present value of our reserves increased by 59% to over $1.6 billion (using a 10% discount rate and constant year end prices of $43.46 for oil and $6.19 for natural gas). The Standardized Measure at December 31, 2004 is $1.2 billion. Standardized Measure differs from PV-10 by $458.9 million, because Standardized Measure includes the effect of asset retirement obligations and future income taxes.

Production volumes for 2004 increased 11% to 9.0 MMBOE (24,665 BOE per day) compared with 2003 production of 8.1 MMBOE (22,218 BOE per day). Oil represented 74% and 81% of our total production in 2004 and 2003, respectively. The increase in production is due to our continued successful development and exploitation program as well as acquisitions.

Net income for 2004 increased to $82.1 million, or $2.58 per diluted share, on revenues of $298.5 million. This compares to 2003 net income of $63.6 million, or $2.10 per diluted share, on revenues of $220.1 million. For 2004, cash flow from operations increased 39% to $171.8 million

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from $123.8 million in cash flow from operations in 2003. The increase in net income and cash flow from operations in 2004 was primarily a result of higher production and higher commodity prices throughout the year.

We invested $187.6 million in development, exploitation, and exploration projects during 2004, including $39.6 million in our high-pressure air injection projects in the Little Beaver unit and the Pennel unit of the CCA. In 2004, we drilled 168 gross operated productive wells and 67 gross non-operated productive wells, for a total of 235 gross productive wells for the year. On a net basis, we drilled 156.4 operated productive wells and participated in 8.8 non-operated productive wells in 2004. Out of the 168 (156.4 net) operated productive wells, 12 (11.5 net) wells were service wells. We also drilled 5 (4.5 net) non-productive wells in 2004, of which 4 (3.9 net) were exploratory wells.

We acquired natural gas producing properties and undeveloped leases in the Overton Field located in Smith County, Texas, additional interests in Elm Grove Field, and all of the capital stock of Cortez Oil & Gas, Inc.

On April 2, 2004, we issued and sold $150.0 million of $6^{1}/_{4}$% Senior Subordinated Notes due April 15, 2014. We received approximately $146.4 million after paying all costs associated with the offering. The net proceeds were used to fund the acquisition of Cortez and repay amounts outstanding under our revolving credit facility.

On June 10, 2004, we issued and sold 2,000,000 shares of our common stock to the public at a price of $26.95 per share. The net proceeds of the offering, after underwriting discounts and commissions and other expenses, were $52.9 million. We used the net proceeds of this offering to repay indebtedness under our revolving credit facility and for general corporate purposes.

On June 30, 2004, we filed a new universal shelf registration statement on Form S-3 with the SEC. The registration statement, which was declared effective by the SEC on July 9, 2004, allows us to issue an aggregate of $500 million of common stock, preferred stock, senior debt and subordinated debt.

On August 19, 2004, we improved our financial flexibility and liquidity by amending and restating our credit facility and increasing our borrowing base from $270 million to $400 million. At December 31, 2004, we had $79 million outstanding under the revolving credit facility, $30 million in outstanding letters of credit, and $291 million available.

Results of Operations

Comparison of 2004 to 2003

Set forth below is our comparison of our results of operations for the year ended December 31, 2004 with our results of operations for the year ended December 31, 2003.

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Revenues and Production. The following table illustrates the primary components of oil and natural gas revenue for the years ended December 31, 2004 and 2003, as well as each year s respective oil and natural gas volumes (dollars in thousands except per unit amounts):

	Year Ended December 31,					
	2004		2003		*Difference*	
	Revenue	$/Unit	Revenue	$/Unit	*Revenue*	*$/Unit*
Revenues:						
Oil wellhead	$ 255,394	$ 38.24	$ 190,203	$ 28.82	*$ 65,191*	*$ 9.42*
Oil hedges	(34,745)	(5.20)	(13,852)	(2.10)	*(20,893)*	*(3.10)*
Total Oil Revenues	$ 220,649	$ 33.04	$ 176,351	$ 26.72	*$ 44,298*	*$ 6.32*
Natural gas wellhead	$ 81,112	$ 5.76	$ 45,218	$ 5.00	*$ 35,894*	*$ 0.76*
Natural gas hedges	(3,228)	(0.23)	(1,473)	(0.17)	*(1,755)*	*(0.06)*
Total Natural Gas Revenues	$ 77,884	$ 5.53	$ 43,745	$ 4.83	*$ 34,139*	*$ 0.70*
Combined wellhead	$ 336,506	$ 37.28	$ 235,421	$ 29.03	*$ 101,085*	*$ 8.25*
Combined hedges	(37,973)	(4.21)	(15,325)	(1.89)	*(22,648)*	*(2.32)*
Total Combined Revenues	$ 298,533	$ 33.07	$ 220,096	$ 27.14	*$ 78,437*	*$ 5.93*

	Production	Average NYMEX $/Unit	Production	Average NYMEX $/Unit	*Production*	Average NYMEX $/Unit
Other data:						
Oil (MBbls)	6,679	$ 41.26	6,601	$ 31.04	*78*	*$ 10.22*
Natural Gas (MMcf)	14,089	6.11	9,051	5.50	*5,038*	*0.61*
Combined (MBOE)	9,027		8,110		*917*	

Oil revenues increased $44.3 million to $220.6 million in 2004 over 2003 as production increased 78 MBbls and our average realized price increased $6.32 per Bbl. Oil revenues were reduced by $34.7 million in 2004 due to our hedging program. The $5.20 per Bbl reduction to our wellhead oil price due to hedging represented a $3.10 per Bbl greater reduction than in 2003. The increase in oil production resulted from success through our 2004 drilling program, uplift from our HPAI program, and acquisitions. In addition, our oil wellhead revenue was reduced by $12.3 million and $5.6 million in 2004 and 2003, respectively, for the net profits interests payments related to our CCA properties.

Natural gas revenues increased in 2004 by $34.1 million to $77.9 million due to increased production of 5,038 MMcf and an increase in the net wellhead price received. The increase in net wellhead price received of $0.76 per Mcf resulted as the average NYMEX price increased $0.61 per Mcf over the same period. The increase in natural gas production resulted from success through our 2004 drilling program and acquisitions.

For the full year 2005, production is expected to increase 8% to 12% from 2004 levels primarily due to our 2005 capital budget of $223.0 million and the full year effect of our 2004 acquisitions.

The prices we receive for our oil and natural gas production are largely based on current market prices, which are beyond our control. For comparability and accountability, we take a constant approach to budgeting commodity prices. We presently analyze our inventory of capital projects on $30.00 per Bbl and $5.00 per Mcf NYMEX prices. We do not assume any escalation of commodity prices when preparing our capital budget. If NYMEX prices trend downward below our base deck, we may reevaluate our capital projects. At these assumed prices, we have forecasted net hedge contract payments of approximately $1.8 million for oil and $0.3 million for natural gas during 2005. However, these amounts will change directly with any change in the market price of oil and natural gas and with any change in our outstanding hedge positions. Additionally, we have anticipated net profits interests payments in 2005 of $6.2 million for

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oil and $0.1 million for natural gas. These payments are highly dependent on the level of drilling in the CCA and on commodity prices, and thus, any change in the level of drilling or fluctuation in commodity prices will have a direct impact on the amount of payments we are required to make. If commodity prices are significantly lower than our forecasted prices of $30.00 for oil and $5.00 for natural gas, it could have a material effect on our projected 2005 results. In this case, we would have to borrow additional money under our existing revolving credit facility, attempt to access the capital markets, or curtail the capital program. If drilling is curtailed or ended, future cash flows could be materially negatively impacted.

In addition to the possibility of a general market decline in oil and natural gas prices, a widening of the difference between the price we are paid and NYMEX prices, which we refer to as the differential, could have a material negative impact on our revenues. Due to a combination of higher prices and increased competition with foreign grades from both Canada and the Middle East, our differential to NYMEX oil widened in the second half of 2004. Early 2005 differentials to NYMEX oil also indicate a further widening. We expect our oil differential in 2005 to remain wider than 2004.

Expenses. The following table summarizes our expenses for the years ended December 31, 2004 and 2003:

	Year Ended December 31,		
	2004	**2003**	***Difference***
Expenses (in thousands):			
Lease operations	$ 47,142	$ 37,846	*$ 9,296*
Production, ad valorem, and severance taxes	30,313	22,013	*8,300*
Depletion, depreciation, and amortization	48,522	33,530	*14,992*
Exploration	3,907		*3,907*
General and administrative (excluding non-cash stock based compensation)	10,982	8,680	*2,302*
Non-cash stock based compensation	1,770	614	*1,156*
Derivative fair value (gain) loss	5,011	(885)	*5,896*
Other operating	5,028	3,481	*1,547*
Interest	23,459	16,151	*7,308*
Current and deferred income tax provision	40,492	36,102	*4,390*
Expenses (per BOE):			
Lease operations	$ 5.22	$ 4.67	*$ 0.55*
Production, ad valorem, and severance taxes	3.36	2.71	*0.65*
Depletion, depreciation, and amortization	5.38	4.13	*1.25*
Exploration	0.43		*0.43*
General and administrative (excluding non-cash stock based compensation)	1.22	1.07	*0.15*
Non-cash stock based compensation	0.20	0.08	*0.12*
Derivative fair value (gain) loss	0.56	(0.11)	*0.67*
Other operating	0.56	0.43	*0.13*
Interest	2.60	1.99	*0.61*
Current and deferred income tax provision	4.49	4.45	*0.04*

Lease operations expense. Lease operations expense increased by $9.3 million in 2004 as compared to 2003. The increase in total lease operations expense resulted from an increase in production volumes as a result of our 2004 drilling program, the Elm Grove, Cortez and Overton acquisitions and our HPAI program, as well as an increase in the per BOE rate. The increase in our average per BOE rate was attributable to acquired properties with higher per BOE expenses and an increase in prices paid for outside services.

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For 2005, we anticipate an increase in total lease operations expense on both an aggregate and a per BOE basis. We anticipate the overall increase due to a full year of production at our Cortez and Overton properties, as well as further implementation of the high-pressure air injection program. Currently, we are capitalizing the HPAI costs on the Little Beaver HPAI project, which will continue until the reservoir becomes fully pressurized. We expect the reservoir to become fully pressurized in 2005 and will begin expensing the costs of injecting air at that time. We have projected lease operations expense of $5.90 per BOE for 2005 as compared to $5.22 for 2004.

Production, ad valorem, and severance taxes. Production, ad valorem and severance taxes increased by $8.3 million in 2004 as compared to 2003. The increase in production, ad valorem, and severance taxes is a direct result of the increase in wellhead revenue. See Revenues and Production above. As a percentage of oil and natural gas revenues (excluding the effects of hedges), production, ad valorem, and severance taxes decreased slightly from 9.4% to 9.0% from 2003 to 2004.

For 2005, total production, ad valorem, and severance taxes will depend in a large part on prevailing oil and natural gas prices. However, the production, ad valorem, and severance tax rate should remain relatively flat at 9.0% of wellhead revenues before hedging.

Depletion, depreciation, and amortization (DD&A) expense. DD&A expense increased by $15.0 million in 2004 as compared to 2003. The increase was primarily due to an increase in production as well as a increase in the per BOE rate. This rate increase was due to the acquisition of the Overton and Cortez properties, which had higher acquisition costs than our historical average, as well as higher drilling costs per BOE of reserves than our historical DD&A rate in certain areas.

We anticipate the total DD&A expense in 2005 will increase due to increased production and our planned 2005 capital expenditures of $223.0 million. We expect the invested capital to add barrels through the drill bit in 2005 at a cost higher than our historical DD&A rate. Assuming capital expenditures do not differ significantly from our budgeted amount, we expect our DD&A rate for 2005 to be approximately $7.00 per BOE. This rate could vary significantly based on actual capital expenditures, production rates, net profits interests, and any acquisitions that close in 2005. Additionally, changes in the market price for oil and natural gas could affect the level of our reserves. As the level of reserves change, the DD&A rate is inversely affected.

Exploration expense. Exploration costs increased in 2004 as we began a drilling exploration program in 2004. As previously discussed, we drilled a record number of wells in 2004, several of which were exploratory wells. We drilled 4 (3.88 net) non-productive exploratory wells at a cost of $2.1 million. This compares to 2003 when zero non-productive exploratory wells were drilled. Three of the exploratory dry holes were drilled in our Montana shallow gas area and one was drilled in the Barnett Shale in our Mid-Continent area. In addition to the increase in dry hole expense, additional exploration-related expenses were incurred in 2004 related to our exploration projects. We incurred abandonment and impairment of undeveloped leases costs of $0.7 million, delay rental expense of $0.2 million, seismic costs of $0.6 million, and other geological and geophysical expenses of $0.3 million.

For 2005, we expect exploration expense to be approximately $6.2 million as we continue our current exploration projects in the Mid-Continent and Montana shallow gas area. This amount could vary considerably, however, based on the success of these projects.

General and administrative (G&A) expense. G&A expense increased by $2.3 million in 2004 over 2003. The increase in G&A expense was a result of increased staffing levels used to manage our growing asset base and outside consulting services used in the evaluation of potential acquisitions and costs associated with compliance with the Sarbanes-Oxley Act of 2002.

We have forecast approximately $14.0 million for general and administrative expenses in 2005 as compared to the $11.0 million incurred in 2004. The increase from 2004 is expected to result from increased staffing to manage our larger asset base, additional expenses related to compliance with the Sarbanes-Oxley Act of 2002, and higher directors and officers insurance costs. Additionally, we have experienced increased competition for human resources from other companies within the industry that has increased the cost to hire and retain experienced industry personnel.

Non-cash stock based compensation expense. Non-cash stock based compensation expense increased from $0.6 million in 2003 to $1.8 million in 2004. This expense represents the amortization of deferred compensation recorded in equity related to restricted stock granted under the 2000 Incentive Stock Plan. This amount is being amortized to expense over the vesting period of the restricted stock.

During the years ended December 31, 2004, 2003, and 2002, we issued 68,071, 45,461, and 77,901 shares, respectively, of restricted stock to employees which depend only on continued employment for vesting. The following table illustrates by year of grant the vesting of shares which remain outstanding at December 31, 2004:

	Year of Vesting					
Year of Grant	**2005**	**2006**	**2007**	**2008**	**2009**	**Total**
2002	23,775	23,775	23,774			71,324
2003		13,772	13,772	13,772		41,316
2004	19,423	19,423	22,690	3,268	3,267	68,071
Total	43,198	56,970	60,236	17,040	3,267	180,711

During the years ended December 31, 2004, 2003, and 2002, we issued 57,693, zero, and 51,427 shares of restricted stock to employees that not only depend on the passage of time and continued employment, but also on certain performance measures for their vesting. The following table illustrates by year of grant the vesting of shares which remain outstanding at December 31, 2004:

	Year of Vesting					
Year of Grant	**2005**	**2006**	**2007**	**2008**	**2009**	**Total**
2002	11,488	11,488	11,488			34,464
2003						
2004			19,231	19,231	19,231	57,693
Total	11,488	11,488	30,719	19,231	19,231	92,157

Deferred compensation of $3.4 million was reclassified within equity from additional paid in capital during the year ended December 31, 2004 in conjunction with the 2004 grants, and will be expensed over the related periods from the grant dates to the vesting dates.

Subsequent to December 31, 2004, we issued 164,703 shares of restricted stock to our employees as part of our annual incentive program. We have projected 2005 non-cash stock based compensation expense related to our restricted stock to be $1.4 million. This amount is dependent somewhat on fluctuations in our stock price because, as noted above, certain awards are accounted for as variable awards as they are based on achievement of certain performance measures.

Derivative fair value (gain) loss. The derivative fair value loss of $5.0 million in 2004 represents the ineffective portion of the mark-to-market loss on our derivative hedging instruments, settlements received on our fixed to floating interest rate swap, (gains) losses related to commodity derivatives not designated as hedges, and changes in the mark-to-market value of our fixed to floating interest rate swap.

In conjunction with the issuance of 8 3/8% notes in June 2002, we entered into an interest rate swap, which swaps fixed rates to floating, with the intent of lowering our effective interest payments. As this transaction does not qualify for hedge accounting, changes in its fair market value, as well as settlements, are not recorded in interest expense, but in Derivative fair value (gain) loss on the Consolidated Statements of Operations. During 2004, a gain of $0.3 million related to this interest rate swap was recorded in Derivative fair value (gain) loss. See Note 12. Financial Instruments to the accompanying consolidated financial statements.

The components of the derivative fair value (gain) loss reported for the year ended December 31, 2004 and 2003 are as follows (in thousands):

		Year Ended December 31,		
		2004	2003	*Increase/ (Decrease)*
Designated cash flow hedges:				
Ineffectiveness	Commodity contracts	$ 5,018	$ 818	*$ 4,200*
Undesignated derivative contracts:				
Mark-to-market (gain) loss	Interest rate swap	272	(2,098)	*2,370*
Mark-to-market (gain) loss	Commodity contracts	(279)	395	*(674)*
Derivative fair value (gain) loss		$ 5,011	$ (885)	*$ 5,896*

Ineffectiveness loss related to our contracts increased $4.2 million due primarily to an increase in oil differentials on our production in the CCA.

Other operating expense. Other operating expense increased $1.5 million in 2004 as compared to 2003. The increase in other operating expense is primarily attributable to $1.3 million increase in oil and natural gas transportation expense, $0.9 million increase in loss on sale of properties and $0.1 million increase in annual corporate taxes, offset by $0.8 million decrease in severance payments to former employees.

For 2005, we anticipate other operating expense to be approximately $6.4 million as compared to $5.0 million in 2004, which reflects the increased transportation costs associated with higher expected production volumes.

Interest expense. Interest expense for the year ended December 31, 2004 increased $7.3 million over 2003 due primarily to an increase in debt outstanding under our credit facility and the new $6^1/4$% notes, offset slightly by a decrease in our weighted average interest rate from period to period. We incurred additional debt in 2004 to fund the Cortez and Overton acquisitions. The weighted average interest rate, net of hedges, for 2004 was 7.7% compared to 9.6% for 2003. This lower weighted average interest rate is the result of the issuance of $150 million aggregate principal amount of $6^1/4$% senior subordinated notes in April 2004.

The following table illustrates the components of interest expense for 2004 and 2003 (in thousands):

	2004	2003	*Difference*
$8^3/8$% senior subordinated notes	$ 12,563	$ 12,563	*$*
$6^1/4$% senior subordinated notes	7,005		*7,005*
Revolving credit facility	1,565	453	*1,112*
Hedge loss amortization	546	1,910	*(1,364)*
Debt issuance cost amortization	969	714	*255*
Fees and other	811	511	*300*
Total	$ 23,459	$ 16,151	*$ 7,308*

Income tax expense. Income tax expense for 2004 increased $4.4 million over 2003. This increase is due primarily to the $23.8 million increase in income before income taxes from 2003 to 2004 offset by a decrease in our effective tax rate from 36.5% in 2003 to 33.0% in 2004. The decrease in effective income tax rate resulted from an incremental increase of $4.0 million for Section 43 credits ($6.1 million in Section 43 credits in 2004 as compared to $2.1 million in 2003) and the effect of the change in our state effective tax rate from 3.0% to 2.4% in 2004 due to changes in the asset mix and apportionment factors.

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Comparison of 2003 to 2002

Set forth below is our comparison of our results of operations for the year ended December 31, 2003 with our results of operations for the year ended December 31, 2002.

Revenues and Production. The following table illustrates the primary components of oil and natural gas revenue for the years ended December 31, 2003 and 2002, as well as each year s respective oil and natural gas volumes (dollars in thousands except per unit amounts):

	Year Ended December 31,					
	2003		2002		*Difference*	
	Revenue	$/Unit	Revenue	$/Unit	*Revenue*	$/Unit
Revenues:						
Oil wellhead	$ 190,203	$ 28.82	$ 141,119	$ 23.38	*$ 49,084*	*$ 5.44*
Oil hedges	(13,852)	(2.10)	(6,265)	(1.04)	*(7,587)*	*(1.06)*
Total Oil Revenues	$ 176,351	$ 26.72	$ 134,854	$ 22.34	*$ 41,497*	*$ 4.38*
Natural gas wellhead	$ 45,218	$ 5.00	$ 24,803	$ 3.03	*$ 20,415*	*$ 1.97*
Natural gas hedges	(1,473)	(0.17)	1,035	0.13	*(2,508)*	*(0.30)*
Total Natural Gas Revenues	$ 43,745	$ 4.83	$ 25,838	$ 3.16	*$ 17,907*	*$ 1.67*
Combined wellhead	$ 235,421	$ 29.03	$ 165,922	$ 22.42	*$ 69,499*	*$ 6.61*
Combined hedges	(15,325)	(1.89)	(5,230)	(0.70)	*(10,095)*	*(1.19)*
Total Combined Revenues	$ 220,096	$ 27.14	$ 160,692	$ 21.72	*$ 59,404*	*$ 5.42*

	Production	Average NYMEX $/Unit	Production	Average NYMEX $/Unit	*Production*	Average NYMEX $/Unit
Other data:						
Oil (MBbls)	6,601	$ 31.04	6,037	$ 26.08	*564*	*$ 4.96*
Natural Gas (MMcf)	9,051	5.50	8,175	3.36	*876*	*2.14*
Combined (MBOE)	8,110		7,399		*711*	

Oil revenues increased $41.5 million in 2003 over 2002 as production increased 564 MBbls and our average realized price increased $4.38 per Bbl. The increase in production resulted from our successful development drilling program and uplift from the HPAI program. Oil revenues were reduced by $13.9 million in 2003 due to our hedging program. The hedging per Bbl reduction to our wellhead oil price of $2.10 represented a $1.06 per Bbl greater reduction than in 2002. The increase in oil production resulted from success through our drilling program, uplift from our HPAI program, and acquisitions In addition, our oil wellhead revenue was reduced by $5.6 million and $2.0 million in 2003 and 2002, respectively, for the net profits interests payments made to others related to our CCA properties.

Natural gas revenues increased in 2003 by $17.9 million due to a 65% increase in the net wellhead price received along with increased production of 876 MMcf. The increase in net wellhead price received of $1.97 per Mcf resulted as the average NYMEX price increased $2.14 per Mcf over the same period. The natural gas production increase resulted from the Elm Grove acquisition during 2003. Averaging 7,984 Mcfe per day from July 31, 2003 (the date of acquisition) to December 31, 2003, the Elm Grove properties added 3,345 Mcfe per day to our average daily production for 2003.

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Expenses. The following table summarizes our expenses for the years ended December 31, 2003 and 2002:

	Year Ended December 31,		
	2003	**2002**	***Difference***
Expenses (in thousands):			
Production			
Lease operations	$ 37,846	$ 30,678	*$ 7,168*
Production, ad valorem, and severance taxes	22,013	15,653	*6,360*
Depletion, depreciation, and amortization	33,530	34,550	*(1,020)*
General and administrative (excluding non-cash stock based compensation)	8,680	6,150	*2,530*
Non-cash stock based compensation	614		*614*
Derivative fair value (gain) loss	(885)	(900)	*15*
Other operating	3,481	2,045	*1,436*
Interest	16,151	12,306	*3,845*
Current and deferred income tax provision	36,102	22,616	*13,486*
Expenses (per BOE):			
Production			
Lease operations	$ 4.67	$ 4.15	*$ 0.52*
Production, ad valorem, and severance taxes	2.71	2.12	*0.59*
Depletion, depreciation, and amortization	4.13	4.67	*(0.54)*
General and administrative (excluding non-cash stock based compensation)	1.07	0.83	*0.24*
Non-cash stock based compensation	0.08		*0.08*
Derivative fair value (gain) loss	(0.11)	(0.12)	*0.01*
Other operating	0.43	0.28	*0.15*
Interest	1.99	1.66	*0.33*
Current and deferred income tax provision	4.45	3.06	*1.39*

Lease operations expense. Lease operations expense increased by $7.2 million in 2003 as compared to 2002. The increase in total lease operations expense resulted from the increase in volumes as a result of our 2003 drilling program, the Elm Grove acquisition and HPAI program. See Revenues and Production above. On a per BOE basis, lease operations expense increased primarily due to (1) full year results of our Paradox Basin properties, which had higher average per BOE lease operations expense of $9.04 for 2003 compared to our average of $4.67 per BOE, (2) the HPAI project on the CCA properties, and (3) lower production volumes from our Lodgepole properties, which have low operating costs.

Production, ad valorem, and severance taxes. Production, ad valorem and severance taxes increased by $6.4 million in 2003 as compared to 2002. The increase in production, ad valorem, and severance taxes for the year ended December 31, 2003 as compared to 2002 is a direct result of the increase in wellhead revenue. See Revenues and Production above. As a percentage of oil and natural gas revenues (excluding the effects of hedges), production, ad valorem, and severance taxes increased slightly from 9.3% to 9.4% from 2002 to 2003.

Depletion, depreciation, and amortization (DD&A) expense. DD&A expense decreased by $1.0 million in 2003 as compared to 2002. Despite an increase in production, DD&A expense decreased in 2003 due to the adoption of SFAS 143 on January 1, 2003, which resulted in a lower per BOE rate. As a result of the adoption of SFAS 143, we can no longer assume proceeds received for the salvage value of our equipment will offset plugging and abandonment costs, and thus are now required to deduct salvage

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value from the book value of equipment in calculating our depreciable base. This was the primary driver of the decrease in the average DD&A rate from 2002 to 2003.

General and administrative (G&A) expense. G&A expense increased by $2.5 million in 2003 as compared to 2002. The increase in G&A expense was a result of increased staffing levels used to manage our growing asset base and outside consulting services used in the evaluation of potential acquisitions.

Non-cash stock based compensation expense. Non-cash stock based compensation expense increased from zero in 2002 to $0.6 million in 2003. This expense represents the amortization of deferred compensation, recorded in equity related to restricted stock granted under the 2000 Incentive Stock Plan. This amount is being amortized to expense over the vesting period of the restricted stock.

During 2002 and 2003, we issued 129,328 and 45,461 shares, respectively, of restricted stock to employees. Of these, 77,901 shares issued in 2002 and 45,461 shares issued in 2003 vest in equal installments on the third, fourth, and fifth anniversary of the date of the grant and depend only on continued employment for future issuance. These represent a fixed award per APB 25 and compensation expense will be recorded over the related service period. Of the remaining 51,427 shares issued in 2002, 34,464 remain outstanding at December 31, 2003. These were issued to two members of senior management and also vest in equal installments on the third, fourth, and fifth anniversary of the date of the grant. However, these shares not only depend on the passage of time and continued employment, but on certain performance measures for their future issuance. These represent a variable award under APB 25 and, thus, the full amount of compensation expense to be recorded for these shares will not be known until their eventual issuance.

Derivative fair value gain/loss. The derivative fair value gain of $0.9 million in 2003 represents the ineffective portion of the mark-to-market loss on our derivative hedging instruments, settlements received on our fixed to floating interest rate swap, any commodity derivatives not designated as hedges, and changes in the mark-to-market value of our fixed to floating interest rate swap.

In conjunction with the issuance of $8^3/8$% notes in June 2002, we entered into an interest rate swap, which swaps fixed rates to floating, with the intent of lowering our effective interest payments. As this transaction does not qualify for hedge accounting, changes in its fair market value, as well as settlements, are not recorded in interest expense, but in Derivative fair value (gain) loss on the Consolidated Statements of Operations. During 2003, a gain of $1.5 million related to this interest rate swap was recorded in Derivative fair value (gain) loss. See Note 12. Financial Instruments to the accompanying consolidated financial statements.

Other operating expense. Other operating expense for the year ended December 31, 2003 increased by approximately $1.4 million as compared to 2002. This amount primarily consists of 2003 severance payment obligations to former employees. The remaining amount relates to the inclusion of accretion expense on our SFAS 143 future abandonment liability; and the abandonment in undeveloped leasehold costs.

Interest expense. Interest expense for the year ended December 31, 2003 increased $3.8 million over 2002 due primarily to an increase in our weighted average interest rate from period to period, as well as an increase in debt outstanding related to our credit facility. We incurred additional debt in 2003 to fund the North Louisiana acquisition. The weighted average interest rate, net of hedges, for 2003 was 9.6% compared to 8.2% for 2002. This higher weighted average interest rate is the result of the issuance of $150 million aggregate principal amount of $8^3/8$% senior subordinated notes in June 2002, which was the primary component of our total indebtedness during 2003, while the revolving credit facility with a lower floating rate was the primary component during the first half of 2002.

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The following table illustrates the components of interest expense for 2003 and 2002 (in thousands):

	2003	2002	*Difference*
$8^3/8$% senior subordinated notes	$ 12,563	$ 6,488	*$ 6,075*
Revolving credit facility	453	2,260	*(1,807)*
Hedge settlements		1,249	*(1,249)*
Hedge loss amortization	1,910	1,619	*291*
Debt issuance cost amortization	714	314	*400*
Fees and other	511	376	*135*
Total	$ 16,151	$ 12,306	*$ 3,845*

Income tax expense. Income tax expense for 2003 increased $13.5 million over 2002. This increase is due primarily to the $38.6 million increase in income before income taxes from 2002 to 2003. Our effective income tax rate, prior to adjusting for Section 43 credits, remained at a constant 38% for both 2002 and 2003. However, during 2003, we generated $2.1 million in Section 43 credits, as compared to $1.1 million of Section 43 credits generated in 2002. This increase resulted in an effective income tax rate of 36.5% in 2003, a decrease of 1% from our 2002 effective rate of 37.5%.

Description of Critical Accounting Estimates

Oil and Natural Gas Properties

Successful efforts method. We utilize the successful efforts method of accounting for our oil and gas properties. Under this method, all costs associated with productive and nonproductive development wells are capitalized. Exploration expenses, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Costs associated with exploratory wells are initially capitalized pending determination of whether the well is economically productive or nonproductive.

All capitalized costs associated with both development and exploratory wells are shown as Development of oil and natural gas properties in the Investing activities section of the Consolidated Statement of Cash Flows. If an exploratory well does not find reserves or does not find reserves in a sufficient quantity as to make them economically producible, the previously capitalized costs are expensed in the Consolidated Statement of Operations and shown as a non-cash adjustment to net income in the Operating activities section of the Consolidated Statement of Cash Flows in the period in which the determination was made. If a determination cannot be made within one year of the exploration well being drilled and no other drilling or exploration activities to evaluate the discovery are firmly planned, all previously capitalized costs associated with the exploratory well are expensed and shown as a non-cash adjustment to net income at that time. Expenditures for redrilling or directional drilling in a previously abandoned well are classified as drilling costs to a proven or unproven reservoir for determination of capital or expense. Expenditures for repairs and maintenance to sustain or increase production from the existing producing reservoir are charged to expense as incurred. Expenditures to recomplete a current well in a different or additional proven or unproven reservoir are capitalized pending determination that economic reserves have been added. If the recompletion is not successful, the expenditures are charged to expense.

Significant tangible equipment added or replaced is capitalized. Expenditures to construct facilities or increase the productive capacity from existing reserves are capitalized. Internal costs directly associated with the development and exploitation of properties are capitalized as a cost of the property and are classified accordingly in our consolidated financial statements. Capitalized costs are amortized on a unit-of-production basis over the remaining life of proved developed reserves or proved reserves, as applicable. Natural gas volumes are converted to equivalent barrels of oil at the rate of six Mcf to one barrel. See Note 2. New Accounting Standards, to the accompanying consolidated financial statements for a discussion of Statement of Financial Accounting Standard No. 143, Accounting for Asset Retirement

Obligations (SFAS 143), which we adopted as of January 1, 2003.

Unproved Properties. We adhere to Statement of Financial Accounting Standards No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies, for recognizing any impairment of capitalized costs to unproved properties. The greatest portion of these costs generally relate to the acquisition of leasehold costs. The costs are capitalized and periodically evaluated as to recoverability, based on changes brought about by economic factors and potential shifts in business strategy employed by management. We consider a combination of time and geologic and engineering factors to evaluate the need for impairment of these costs. Unproved properties had a net book value of $29.7 million and $0.9 million as of December 31, 2004 and 2003, respectively. We recorded a charge for unproved acreage impairment in the amount of $0.7 million, $0.4 million, and zero in 2004, 2003, and 2002, respectively.

Oil and Natural Gas Reserves. Assumptions used by the independent reserve engineers in calculating reserves or regarding the future cash flows or fair value of our properties are subject to change in the future. Future prices received for production and future production costs may vary, perhaps significantly, from the prices and costs assumed for purposes of calculating reserve estimates. We may not be able to develop proved reserves within the periods estimated. Furthermore, prices and costs will not remain constant. Actual production may not equal the estimated amounts used in the preparation of reserve projections. As these estimates change, the amount of calculated reserves change. Any change in reserves directly impacts our estimate of future cash flows from the property, as well as the property s fair value.

Impairment. Impairments of proved oil and natural gas properties are directly affected by our reserve estimates. We are required to assess the need for an impairment of capitalized costs of oil and natural gas properties and other long-lived assets whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. If impairment is indicated based on a comparison of the asset s carrying value to its undiscounted expected future net cash flows, then it is recognized to the extent that the carrying value exceeds fair value. Each part of this calculation is subject to a large degree of management judgment, including the determination of property s reserves, amount and timing of future cash flows, and fair value.

Depletion, Depreciation, and Amortization (DD&A). DD&A expense is directly affected by our reserve estimates. Any change in reserves directly impacts the amount of DD&A expense that we recognize in a given period. Assuming no other changes, such as an increase in depreciable base, as our reserves increase, the amount of DD&A expense in a given period decreases and vice versa. Changes in future commodity prices would likely result in increases or decreases in estimated recoverable reserves. Additionally, Miller & Lents, Ltd., our independent reserve engineers, estimate our reserves once a year at December 31.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the purchase of Cortez Oil & Gas, Inc. in April 2004 (see Note 3, Acquisitions). We test goodwill for impairment quarterly by applying a fair-value based test. We would recognize an impairment charge for any amount by which the carrying amount of goodwill exceeds its fair value. We tested goodwill for impairment and used discounted cash flows to establish fair values for the Company as a whole. The test indicated no impairment for 2004.

Net Profits Interests

A major portion of our acreage position in the Cedar Creek Anticline is subject to net profits interests (NPI) ranging from 1% to 50%. The holders of these net profits interests are entitled to receive a fixed percentage of the cash flow remaining after specified costs have been deducted from net revenue. The net profits calculations are contractually defined, but in general, net profits are determined after considering operating expense, overhead expense, interest expense, and drilling costs. The amounts of reserves and production calculated to be attributable to these net profits interests are deducted from our reserves and production data, and our revenues are reported net of NPI payments. The reserves and production that are attributed to the NPIs are calculated by dividing estimated future NPI payments (in the case of reserves) or prior period actual NPI payments (in the case of production) by the commodity prices current at the determination date. Fluctuations in commodity prices and the levels of development activities in the CCA from period to period will impact the reserves and production attributed to the NPIs and will have an inverse effect on our reported reserves and production. Based largely on higher commodity prices, we expect to make higher net profit interest payments in 2005 and possibly beyond than we have in previous years, which directly impacts our revenues, production, reserves, and net income.

Revenue Recognition

Revenues are recognized for our share of jointly owned properties as oil and natural gas is produced and sold, net of royalties and net profits interest payments. Natural gas revenues are also reduced by any processing and other fees paid except for transportation costs paid to third parties which are recorded as expense. Natural gas revenue is recorded using the sales method of accounting whereby revenue is recognized as natural gas is sold rather than as it is produced. Royalties, net profits interests, and severance taxes are paid based upon the actual price received from the sales. To the extent actual quantities and values of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, we estimate and record the expected sales volumes and price for those properties. We also do not recognize revenue for the production in tanks or pipelines that has not been delivered to the purchaser yet. Our net oil inventories in pipelines were 43,010 Bbls and 46,622 Bbls at December 31, 2004 and 2003, respectively. Natural gas imbalances under-delivered to us at December 31, 2004 and December 31, 2003, were 540,000 MMBTU and 446,000 MMBTU, respectively.

Income Taxes

Section 43 Credits. Section 43 of the Internal Revenue Code (the Code) allows a 15 percent tax credit for certain enhanced oil recovery project costs incurred in the United States. We believe project costs incurred related to our HPAI tertiary recovery project on the CCA qualify under the provisions of the Code and, therefore, we have reduced income tax expense by 15 percent of project costs incurred to date. The tax basis for the properties (and related intangible drilling cost deductions and future depreciation deductions) is reduced by the amount of the enhanced oil recovery tax credit. In order to qualify for the credits a project must meet all of the following requirements:

1. The project involves the application of one or more qualified tertiary recovery methods that is reasonably expected to result in more than an insignificant increase in the amount of crude oil that ultimately will be recovered;

2. The project is located within the United States;

3. The first injection of liquids, gases, or other matter for the project occurs after December 31, 1990; and

4. The project is certified by a petroleum engineer.

According to the Code, the costs that will qualify for the credit when paid or incurred in connection with a qualifying enhanced oil recovery project include:

1. *Tangible Property.* Any amount paid for tangible property that is an integral part of a qualified enhanced oil recovery project, and with respect to which depreciation is allowable.

2. *Intangible Drilling and Development Costs.* Intangible drilling cost with respect to which the taxpayer may make an intangible drilling costs deduction election under Code Sec. 263(c).

3. *Qualified Tertiary Injectant Expenses.* Any qualified tertiary injectant expenses for which a deduction is allowable under any Code section.

If our federal income tax returns are reviewed by the Internal Revenue Service (the IRS), the IRS could disagree with our decision and disallow a portion of the credit. While we believe our HPAI project qualifies for the tax credit and that our accounting and tracking of the costs related to the project are

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accurate, should the IRS disagree with our position, we would be required to record additional income tax expense to the extent income tax expense has previously been reduced related to the generation of Section 43 credits.

Effective Tax Rate. The Company s effective tax rate is subject to variability from period to period as a result of factors other than changes in federal and state tax rates and/or changes in tax laws which can affect tax paying companies. Currently, our effective tax rate varies primarily as the amount of Section 43 income tax credits generated varies from period to period. These credits are generated by paying or incurring certain costs in connection with a qualifying enhanced oil recovery project, such as our current high-pressure air injection projects underway in the CCA. Our effective tax rate is also affected by changes in the allocation of property, payroll, and revenues between states in which we own property as rates vary from state to state.

Stock-based Compensation

Employee stock options and restricted stock awards are accounted for under the provisions of Accounting Principles Board Opinion No. 25 (APB 25), Accounting for Stock Issued to Employees. Accordingly, no compensation is recorded for stock options that are granted to employees or non-employee directors with an exercise price equal to or above the common stock price on the grant date. If compensation expense for the stock based awards had been determined using the provisions of SFAS 123, our net income and net income per share would have been adjusted to the pro forma amounts indicated below (in thousands, except per share amounts):

	Year Ended December 31,		
	2004	**2003**	**2002**
As Reported:			
Non-cash stock based compensation (net of taxes)	$ 1,108	$ 381	$
Net income	82,147	63,641	37,685
Basic net income per share	2.62	2.11	1.25
Diluted net income per share	2.58	2.10	1.25
Pro Forma:			
Non-cash stock based compensation (net of taxes)	$ 2,289	$ 1,929	$ 1,277
Net income	80,966	62,093	36,408
Basic net income per share	2.58	2.06	1.21
Diluted net income per share	2.54	2.05	1.21

During the year ended December 31, 2004, 6,509 employee stock options and 9,236 shares of restricted stock that were issued and outstanding at December 31, 2003 were forfeited.

Hedging and Related Activities

We use various financial instruments for non-trading purposes to manage and reduce price volatility and other market risks associated with our crude oil and natural gas production. These arrangements are structured to reduce our exposure to commodity price decreases, but they can also limit the benefit we might otherwise receive from commodity price increases. Our risk management activity is generally accomplished through over-the-counter forward derivative contracts executed with large financial institutions. We also use derivative instruments in the form of interest rate swaps, which hedge our risk related to interest rate fluctuation.

We currently recognize all of our derivative and hedging instruments in our statements of financial position as either assets or liabilities and measure them at fair value. If a derivative does not qualify for hedge accounting, it must be adjusted to fair value through earnings. However, if a derivative does qualify for hedge accounting, depending on the nature of the hedge, changes in fair value can be offset against the change in fair value of the hedged item through earnings or recognized in other comprehensive income until such time as the hedged item is recognized in earnings.

To qualify for cash flow hedge accounting, the cash flows from the hedging instrument must be highly effective in offsetting changes in cash flows due to changes in the underlying items being hedged. In addition, all hedging relationships must be designated, documented, and reassessed periodically. Most of our derivative financial instruments qualify for hedge accounting. Cash flow hedges are marked-to-market through comprehensive income each quarter.

Currently, all of our derivative financial instruments that are designated as hedges are designated as cash flow hedges. These instruments hedge the exposure of variability in expected future cash flows that is attributable to a particular risk. The effective portion of the mark-to-market gain or loss on these derivative instruments is recorded in Other Comprehensive Income in Stockholders Equity and reclassified into earnings in the same period in which the hedged transaction affects earnings. Any ineffective portion of the gain or loss is recognized as Derivative fair value (gain) loss in the Consolidated Statements of Operations immediately. While management does not anticipate changing the designation of any of our current derivative contracts as hedges, factors beyond our control can preclude the use of hedge accounting. One example would be variability in the NYMEX price for oil or natural gas, upon which many of our commodity derivative contracts are based, that does not coincide with changes in the spot price for oil and natural gas that we are paid. Another example would be if the counterparty to a derivative contract was deemed no longer creditworthy and non-performance under the terms of the contract was likely. To the extent our derivative contracts are not designated as hedges, high earnings volatility can result, as any future changes in the market value of the contract would then be marked-to-market through earnings.

New Accounting Standards

In December 2004, the FASB issued Statement No. 123 (revised 2004), Share-Based Payment (SFAS 123(R)), which replaces SFAS 123, Accounting for Stock-Based Compensation, and supersedes APB 25. SFAS 123(R) requires the measurement of all share-based payments to employees, including grants of employee stock options, using a fair-value-based method and the recording of expense in our Consolidated Statements of Operations. The accounting provisions of SFAS 123(R) are effective for reporting periods beginning after June 15, 2005. We are required to adopt SFAS 123(R) in the third quarter of 2005. The pro forma disclosures previously permitted under SFAS 123 no longer will be an alternative to financial statement recognition. See Stock-based Compensation above for the pro forma net income and net income per share amounts, for fiscal 2002 through fiscal 2004, as if we had used a fair-value-based method similar to the methods required under SFAS 123(R) to measure compensation expense for employee stock incentive awards.

In December 2004, the FASB issued FASB Staff Position No. FAS 109-1 (FAS 109-1), Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004. The American Jobs Creation Act introduces a new IRS code section, Section 199, which provides a deduction equal to 3% (increasing to 9% when fully phased-in in 2010) of taxable income from a qualified production activity. FAS 109-1 clarifies that this tax deduction should be accounted for as a special tax deduction in accordance with Statement 109, thereby reducing tax expense in the periods in which the deductions are deductible on the tax return. We do not expect the adoption of these new tax provisions to have a material impact on our consolidated financial position, results of operations, or cash flows.

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Capital Resources, Capital Commitments, and Liquidity

Capital Resources and Capital Commitments

Our primary capital resources are net cash provided by operating activities and proceeds from financing activities. Our primary needs for cash are as follows:

Development, exploitation, and exploration of our existing oil and natural gas properties

High-pressure air injection programs on our CCA properties

Acquisitions of oil and natural gas properties

Leasehold and acreage costs

Other general property and equipment

Funding of necessary working capital

Payment of contractual obligations

For 2005, our Board of Directors has approved the following $223.0 million capital budget, excluding potential proved property acquisitions (in thousands):

	2005
Budgeted Capital Expenditures:	
Development, exploitation, and exploration	$ 191,500
HPAI	26,000
Leasehold and acreage acquisition	4,000
Other PP&E	1,500
Total	$ 223,000

We analyze our inventory of capital projects based on $30.00 per Bbl and $5.00 per Mcf NYMEX prices. We do not assume any escalation of commodity prices when preparing our capital budget. If NYMEX prices trend downward below our base deck, we may reevaluate capital projects and may adjust the capital budgeted for development, exploitation, and exploration investments accordingly.

Development, Exploitation, and Exploration. Our capital expenditures for development, exploitation, and exploration during the years ended December 31, 2004, 2003, and 2002 were as follows (in thousands):

	Year Ended December 31,		
	2004	2003	2002
Development, Exploitation, and Exploration Expenditures:			
Development and exploitation	$ 117,464	$ 86,078	$ 73,671
HPAI	39,628	12,899	6,642
Exploration	30,546		
Total	$ 187,638	$ 98,977	$ 80,313

For 2005, we expect to invest $191.5 million in development, exploitation, and exploration projects.

High-Pressure Air Injection. In 2003, we began implementing our second HPAI program in the Little Beaver unit of the CCA and began injecting air in the reservoir in December 2003. At Little Beaver, we completed the implementation of Phase I and Phase II during 2004. The reservoir is pressuring up in line with forecasts and we expect to see initial production uplift mid-year 2005. In 2002 we began Phase I of Little Beaver unit of CCA spending $6.6 million in development capital.

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For 2005, we have budgeted $26.0 million for high-pressure air injection capital, primarily related to our Pennel program.

Acquisitions, Leasehold and Acreage Costs. Our capital expenditures for oil and natural gas proved property acquisitions during the years ended December 31, 2004, 2003, and 2002 were as follows (in thousands):